UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

ALLETE, Inc. (d/b/a Minnesota Power)

v. Docket No. EL06-69-000

Midwest Independent Transmission
System Operator, Inc.

ORDER DENYING COMPLAINT

(Issued May 17, 2007)

1. On May 8, 2006, ALLETE, Inc. (d/b/a Minnesota Power) (Minnesota Power)[1] filed a complaint against Midwest Independent Transmission System Operator, Inc. (Midwest ISO),[2] seeking financial relief from an alleged error in Midwest ISO's Day-Ahead pricing model. Minnesota Power claims that this alleged error led to erroneous

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[1] Minnesota Power, a division of ALLETE, Inc., is an investor-owned public utility that provides retail and wholesale electric service in northeastern Minnesota. It is a transmission-owning member of Midwest ISO and a market participant in the Midwest ISO market with market-based rate authority. Minnesota Power also owns generation and distribution assets.

[2] Midwest ISO is the Commission-approved regional transmission organization for the Midwest region. Midwest ISO operates under its Open Access Transmission and Energy Markets Tariff (TEMT), which provides for a market-based congestion management program and energy market in the Midwest ISO region, including Day-Ahead and Real-Time energy markets with locational marginal pricing and a market for financial transmission rights. *See Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 (TEMT II Order), *order on reh'g*, 109 FERC ¶ 61,157 (2004), *order on reh'g*, 111 FERC ¶ 61,043 (2005).

Day-Ahead Locational Marginal Prices (LMPs) at Minnesota Power's Boise Load Node (Boise Node) on September 13, 2005, causing Minnesota Power to suffer excessive charges equal to approximately $550,000. Minnesota Power further claims that Midwest ISO determined through its Market Settlement Dispute process, which is explained more fully below, that the Day-Ahead LMPs at the Boise Node should not be recalculated and thus no "excess charges" should be refunded to Minnesota Power. Minnesota Power requests that the Commission direct Midwest ISO to adjust the allegedly erroneous LMPs at the Boise Node for September 13, and to refund, with interest, the allegedly excessive charges paid by Minnesota Power.

2. We will deny Minnesota Power's complaint because Minnesota Power has not substantiated its allegations that there was a market implementation error by Midwest ISO, the LMPs at the Boise Node appear to be a result of general market conditions on September 13, and there is no evidence of a modeling error in Midwest ISO's Day-Ahead market model. Prices on September 13 reflected the operation of Midwest ISO's market rules and reflected scarcity conditions in the market. Accordingly, we find that there is no basis to grant the requested changes to the September 13 LMPs at the Boise Node. We further find that there is no reason for this complaint to be set for hearing.

Complaint

3. In its complaint, Minnesota Power argues that the Day-Ahead LMPs at the Boise Node on September 13 were significantly and anomalously high.[3] On September 13, Day-Ahead LMPs at the Boise Node averaged $566.87 for the on-peak period and ranged from $97.68 to a peak of $972.01.[4] Minnesota Power states that this was by far the highest peak for any commercial node in Midwest ISO for that day, as LMPs at other points on the system never exceeded $318.03, with the highest average on-peak LMP at another node being $193.13.[5] Minnesota Power asserts that LMPs were also atypical for the Boise Node, as compared to other days, pointing out that the on-peak average LMPs for September 12 and 14 at the Boise Node were $100.84 and $74.55, respectively.[6]

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[3] Minnesota Power's complaint includes an Affidavit of Bradley Oachs, Director – Energy Supply and Asset Optimization for Minnesota Power.

[4] Minnesota Power Complaint, Exhibit 2.

[5] Minnesota Power Complaint, Exhibit 2.

[6] Minnesota Power Complaint, Exhibit 1.

4. Minnesota Power states that it contacted Midwest ISO via e-mail on October 3, 2005, requesting an explanation of the September 13 Boise Node Day-Ahead LMPs.[7] On October 6, 2005, Minnesota Power submitted a Market Settlement Dispute[8] to Midwest ISO for recovery of approximately $550,000, which it calculated to be the total financial impact of the allegedly excessive September 13 Day-Ahead LMPs, including congestion charges and impacts upon Minnesota Power's Firm Transmission Rights (FTRs). Specifically, Minnesota Power sought approximately $385,000 due to excess congestion charges and $175,000 associated with Minnesota Power's FTRs.[9] Minnesota Power calculates the alleged excess congestion charges based on the differences between the Day-Ahead marginal congestion charges at the Boise Node and the Day-Ahead marginal congestion charges at Minnesota Power's Boswell 3 generator node.[10] Minnesota Power also says that the inflated Boise Node LMPs directly increased the LMPs at the node for the Ontario Independent Electric Operator (IMO), resulting in the excess FTR costs.

5. Midwest ISO responded on October 24, 2005, stating that the September 13 Day-Ahead LMPs at the Boise Node were:

> driven by phase shifter and loop flow assumptions that were used in the case. The modeling assumptions contributed to the binding of a constraint local to Boise. The phase shifter and loop flow inputs used in the [Day-Ahead] Market cases have been reviewed and updated to more accurately reflect conditions expected to occur in [Real-Time].[11]

6. On October 25, 2005, Minnesota Power replied to Midwest ISO that given that "the problem was a modeling issue," it assumed that Minnesota Power's Market

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[7] Minnesota Power Complaint, Bradley Oachs Affidavit at 3.

[8] Midwest ISO market participants can contest Energy Market Settlement outcomes through the Market Settlement Process by submitting a Market Settlement Dispute to Midwest ISO. *See* Midwest ISO's Business Practices Manual for Market Settlements, No. 5, Version 8, at 5-1 through 5-9 (December 22, 2005).

[9] Minnesota Power Complaint, Exhibit 4 at 1 and 2.

[10] Minnesota Power states that it uses the Boswell 3 generator node as the reference source for the congestion charges because it is representative of the marginal congestion charges for the Minnesota Power generation that serves the Minnesota Power load at the Boise Node.

[11] Minnesota Power Complaint, Exhibit 7 at 2.

Settlement Dispute for the September 13 alleged overcharges would be approved.[12] Midwest ISO, however, denied Minnesota Power's Market Settlement Dispute on October 25, 2005, basing its finding on its conclusions specified in the October 24, 2005 response above.[13]

7. Minnesota Power also states that it is unable to verify the accuracy of Midwest ISO's Day-Ahead modeling assumptions, making it impossible to determine the exact nature of the error that caused the "excessive pricing" at the Boise Node on September 13. Minnesota Power states that it is at the mercy of Midwest ISO and any other market participants submitting possibly erroneous data, because Minnesota Power has no way to verify the accuracy of the assumptions in the pricing models.

8. Minnesota Power claims that Midwest ISO can use price correction procedures found in section 48 of Midwest ISO's TEMT as a mechanism to change the September 13 Day-Ahead LMPs at the Boise Node. Section 48 of the TEMT provides Midwest ISO price correction authority for market implementation errors and emergency system conditions in the energy markets.[14] Minnesota Power cites to Commission precedent for the proposition that the price correction procedures provide for corrective measures in the event of a temporary inability to calculate accurate market LMPs due to data errors, software errors, malfunction of ISO equipment, or outages of generation or transmission equipment.[15] Minnesota Power asserts that erroneous phase shifter[16] and loop flow assumptions used by Midwest ISO on September 13 and the resulting Day-Ahead LMPs at the Boise Node constitute a market implementation error due to a data error. It points to Midwest ISO TEMT's definition of market implementation errors as "[f]laws in the design or implementation of software resulting in changes in LMPs or

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[12] *Id*. at 3.

[13] Minnesota Power Complaint, Exhibit 8.

[14] TEMT section 48.3(d) provides that Midwest ISO has the ability to "recalculate changes in LMPs or other prices cleared through the Energy Markets and the corresponding changes in Settlements in a manner that reflects, as close as reasonably practicable, the LMPs or other prices that would have cleared through the Energy Markets but for the Market Implementation Error or Emergency System Conditions . . . ."

[15] *See Midwest Independent Transmission System Operator, Inc.*, 110 FERC ¶ 61,049, at P 54 (2005) (TEMT II Compliance Order).

[16] "Phase shifter" and "phase angle regulator" are different terms for the same elements in the model and are used interchangeably herein.

other prices cleared through the Energy Markets and the corresponding changes in Settlements not accurately reflecting the application of the Market Rules."[17]

9. In support of its arguments, Minnesota Power also points to a Commission order denying a complaint against New York ISO, in which the Commission found the recalculation of energy LMPs in New York ISO to be consistent with the filed rate doctrine.[18] Minnesota Power believes Midwest ISO similarly calculated incorrect LMPs for the Boise Node for September 13 and thus should be directed to recalculate a rate that would be consistent with the filed rate under the TEMT. Minnesota Power notes that it is aware that the Commission has not required ISOs to recalculate LMPs for modeling assumption errors in each instance. Minnesota Power, however, states that a recalculation is required in this instance, because the modeling assumption error it alleges resulted in LMPs that were seven hundred percent higher than the average LMP. Further, Minnesota Power states its belief that repricing at the Boise Node would require limited recalculations and would affect few market participants.

10. Minnesota Power requests that the Commission direct Midwest ISO to recalculate the allegedly erroneous Day-Ahead LMPs for September 13 at the Boise Node and refund, with interest, the allegedly excessive charges.

Notice of Filing, Responsive Pleadings, and Data Request Matters

11. Notice of Minnesota Power's complaint was published in the *Federal Register*, with answers, interventions, and protests due on or before May 29, 2006.[19] An answer was timely filed by Midwest ISO, and on June 14, 2006, Minnesota Power responded to Midwest ISO's answer. A timely motion to intervene raising no issues was filed by Wisconsin Public Service Corporation, Upper Peninsula Power Company, WPS Energy Services, Inc., and WPS Power Development, LLC.

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[17] TEMT section 1.182(b).

[18] *See NRG Power Marketing Inc. v. New York Indep. Sys. Operator, Inc.*, 91 FERC ¶ 61,346, at 62,166 (2000) (*NRG*). In *NRG*, the Commission allowed New York ISO's recalculation of energy prices to stand even though it was accomplished outside the timeframe for price correction under the New York ISO tariff, because it found that there was an erroneous calculation of the formula rate, and therefore, the ISO had an obligation under the filed rate doctrine to correct prices that do not reflect the operation of its market rules (which are the filed rate).

[19] 71 Fed. Reg. 28,317 (2006)

12. On July 11, 2006, Commission staff issued a data request to Midwest ISO seeking additional information to assist the Commission in reaching a decision in this proceeding. On August 10, 2006, Midwest ISO filed public and non-public versions of its data responses, stating that its responses contained commercially and competitively sensitive information and requesting confidential treatment of certain information. On September 11, 2006, Minnesota Power filed a motion for a protective order and for access to the confidential information. The Midwest ISO filed a response.

13. In an order issued October 23, 2006, the Commission granted Minnesota Power's motion for a protective order and release of the non-public version of Midwest ISO's data responses pursuant to a protective order.[20] On November 13, 2006, Minnesota Power filed additional comments with the Commission based on its review of the non-public data responses. On November 28, 2006, Midwest ISO filed a response.

Midwest ISO Answer

14. Midwest ISO maintains that the September 13 Day-Ahead LMPs at the Boise Node were not due to modeling errors, but were due to the combined effect of offers and bids (including Minnesota Power's inflexible demand bids), transmission system topology and model assumptions, including assumptions related to loop flow and phase angle regulator settings, as explained more fully below.[21] As such, it asks the Commission to deny Minnesota Power's complaint and requested relief.

15. Midwest ISO states that its initial review showed that the September 13 Day-Ahead market model accurately reflected network topology based on the scheduled transmission outages for that day. The review also showed binding constraints on September 13 at Little Fork (a node just south of the Boise Node). Midwest ISO explains that one reason for the September 13 Day-Ahead LMPs is the interrelationship between the LMPs at Little Fork, the LMPs at the Boise Node, and Minnesota Power's inflexible demand bid (*i.e.*, fixed and not responsive to price) at the Boise Node. Midwest ISO states that the congestion at Little Fork resulted in the elevated LMPs at the Boise Node. Midwest ISO concluded that the congestion at Little Fork resulted from several factors including loop flow assumptions, phase angle regulator settings, scheduled transmission

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[20] *See Allete, Inc. (d/b/a Minnesota Power) v. Midwest Independent Transmission System Operator, Inc.*, 117 FERC ¶ 61,090 (2006) (October 23 Order).

[21] Midwest ISO's answer includes an affidavit of Todd Ramey, Manager of Energy Market Administration for Midwest ISO.

outages, competing injections and withdrawals by physical and virtual generation and load, and physical interchange transactions.[22]

16. Further, Midwest ISO states that the transactional and assumption-based flows resulted in Midwest ISO to IMO exports at Day-Ahead levels that were higher than levels that were actually experienced in Real-Time, as is common in the Day-Ahead market. In particular, Midwest ISO explains that the availability of virtual supply and demand offers in the Day-Ahead market can result in model flows that deviate from flows that might be expected in the Real-Time market. When this occurs, there will be congestion in the Day-Ahead market to ration the limited transmission capacity among the competing market injection and withdrawal transactions.

17. Midwest ISO states that the Day-Ahead market can ration transmission capacity by the dynamic balancing of bids and offers, and, in some cases, with controllable transmission devices such as phase angle regulators. In this case, Midwest ISO explains that a phase angle regulator at the International Falls substation was used to control flow between Midwest ISO and IMO, and that its Day-Ahead market setting is an input to the Day-Ahead market model based upon expected Real-Time market conditions.

18. Midwest ISO states that, in the September 13 Day-Ahead market model, the International Falls phase angle regulator was set based on then current Real-Time experience and had been given a flexibility band to allow the phase angle regulator to help control transmission congestion, as are all phase angle regulators on Midwest ISO's system. When the model was run, the combined impact of outages, loop flow inputs, phase angle regulator settings, and competing requests for Day-Ahead injections and withdrawals, resulted in high south-to-north flows towards the IMO through Little Fork towards the Boise Node and International Falls. To control the flow to IMO, the International Falls phase angle regulator moved within the range of flexibility provided by the band. However, even when the phase angle regulator flexibility was fully utilized, flow limits were reached at Little Fork forming a constraint there.

19. Midwest ISO states that, on September 13, price sensitive transactions at the IMO interface were the most effective resources to control flows at Little Fork given Minnesota Power's inflexible load bid at the nearby Boise Node, and thus LMPs rose at

[22] Midwest ISO also explains that while the underlying transmission system in the Day-Ahead and Real-Time models is identical, there may be network topology differences between the two models due to differences between planned and actual transmission outages, and other inputs such as loop flow, thermal ratings, and settings of phase angle regulators for which Midwest ISO attempts to approximate Real-Time conditions.

IMO. Midwest ISO explains that, because the IMO interface has relatively lower electrical sensitivity to Little Fork, large amounts of redispatched energy at the IMO interface are needed to achieve relatively small amounts of flow change at Little Fork. Thus, although the IMO interface transactions were the most cost effective in managing the constraint at Little Fork, they still resulted in a relatively high shadow price (a direct measure of the cost of managing the constraint) at Little Fork. Midwest ISO concludes that the combination of: (1) the high shadow price at Little Fork; (2) the high sensitivity of the Boise Node to Little Fork; and (3) the inflexible load bid at the Boise Node, resulted in relatively high LMPs at the Boise Node on September 13.

20. Midwest ISO states that loop flow assumptions and phase angle regulator settings used in the Day-Ahead market model are periodically reviewed and updated by Midwest ISO's engineering group to better align the assumptions with conditions being experienced in Real-Time.[23] Midwest ISO also states that the price correction mechanism set forth in the TEMT is intended to correct market implementation errors and emergency system conditions, but neither was involved in the increased LMPs at the Boise Node on September 13.

21. Midwest ISO adds that Minnesota Power erroneously interprets Midwest ISO's review of the phase angle regulator and loop flow inputs used in the Day-Ahead market model, and the update of such inputs to more accurately reflect the conditions expected in Real-Time, as an acknowledgement of "modeling errors." Midwest ISO states that "just as evidence of future repairs is not evidence of negligence," its review and updating of the Day-Ahead market model does not mean that the previous model of the Day-Ahead market is flawed or that Midwest ISO made a modeling error.[24] Midwest ISO states that the phase angle regulator assumptions in the September 13 Day-Ahead market model were based on the then current Real-Time experience.[25] Midwest ISO states that the phase angle regulator and loop flow modeling assumptions were updated to more accurately reflect the conditions expected to occur in Real-Time. Midwest ISO says that such updates are a routine element of market operations and are necessary to assure that the assumptions utilized in the Day-Ahead market model reflect changing Real-Time conditions.[26] Accordingly, Midwest ISO asks the Commission to deny Minnesota Power's complaint.

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[23] Ramey Affidavit at 7.

[24] Midwest ISO Answer at 9.

[25] Ramey Affidavit at 6.

[26] Midwest ISO Answer at 9, *citing Wisconsin Public Service Comm'n v. Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,131 (2005).

<u>Responses</u>

<u>Minnesota Power Answer</u>

22. Minnesota Power argues that Midwest ISO has provided very little real information to explain how the price spike on September 13 occurred. Minnesota Power argues that Midwest ISO only provided general information regarding this pricing anomaly and has not provided any detailed data that would allow Minnesota Power to verify the input assumptions underlying the LMP calculations.[27] Minnesota Power also states that many of the facts presented by Midwest ISO in its answer are new to Minnesota Power.

23. Minnesota Power states that Midwest ISO's assertion, that the pricing anomaly at the Boise Node is not due to modeling of the phase angle regulator and loop flows affecting this node, changes the "facts" that Midwest ISO initially presented to Minnesota Power.[28] Minnesota Power says it is hamstrung by Midwest ISO's unwillingness to share detailed information underlying its Day-Ahead modeling assumptions with Minnesota Power, and therefore has no way to verify whether this new assertion is correct. Minnesota Power also contests Midwest ISO's claim that Minnesota Power's inflexible demand bid for the Boise Node contributed to the high LMPs on September 13 and that the high LMPs would not have occurred but for Minnesota Power's inflexible bid.[29] It says that, in Minnesota Power's experience, the phase angle regulator that was designed to control flows over this path has historically prevented congestion at the Boise Node. Minnesota Power says that the bidding practices of Minnesota Power at the Boise Node should not be in question, as it should not have to anticipate modeling errors.

[27] As noted above, and explained more fully below, Midwest ISO later provided Minnesota Power with additional (confidential) information under a protective order.

[28] Minnesota Power Answer at 3, *citing* to Midwest ISO Answer at 6, stating that "[c]ontrary to Minnesota Power's claim, the Day-Ahead LMPs at the Boise Node for September 13 were not due to modeling errors, but were due to the combined effect of offers and bids (including Minnesota Powers [sic] inflexible demand bids), transmission system topology and model assumptions, including assumptions related to loop flow and [phase angle regulator] settings."

[29] Minnesota Power says that it is unclear why Minnesota Power should rely on a flexible bid to prevent the effects of a Day-Ahead price increase that may be caused by inaccurate modeling and/or underlying assumptions. Further, Minnesota Power says there was no reason for Minnesota Power to submit a flexible demand bid, as Minnesota Power had no expectation that there would be congestion at this facility.

24. Minnesota Power also states that, although it believes that recalculation of the LMPs should affect only one node, Midwest ISO has not provided Minnesota Power with any information to determine how many market participants could be affected by recalculated LMPs at the node. Nonetheless, Minnesota Power states that the price correction measures in the TEMT were designed to prevent this type of implementation error. As such, Minnesota Power states that the Commission should order the improper charges refunded, or, in the alternative, that the complaint should be set for hearing to accurately determine the cause of the high LMPs at the Boise Node, in order to prevent such LMPs from occurring in the future.

Minnesota Power Comments on Confidential Data

25. Minnesota Power filed additional comments once it was given access to the confidential data submitted by Midwest ISO pursuant to the Commission's October 23 Order. Minnesota Power notes that it is difficult to provide detailed comments on Midwest ISO's data responses because it believes there is little context in which to interpret the information without further information from Midwest ISO. Minnesota Power asserts that without a better understanding of the workings of Midwest ISO's commercial model with respect to the phase angle regulator and the other data provided by Midwest ISO, meaningful review of the data and its effect on LMPs cannot occur. With this caveat, Minnesota Power believes that the International Falls phase angle regulator limits were set in an extremely narrow band on September 12 and 13 compared to the setting for September 14. Minnesota Power argues that, had Midwest ISO used the proper settings on September 13, the excessive charges to Minnesota Power might have been avoided.

26. Minnesota Power also points to Midwest ISO's branch flow model documents indicating that the branch flow is constrained by the branch flow capacity limit.[30] Minnesota Power states that it is unsure what branch flow limit Midwest ISO used for the phase angle regulator. Minnesota Power says that, normally, the phase angle regulator should respect the 150 MW south and 100 MW north flowgate limits, but it appears to Minnesota Power that Midwest ISO did not use these limits in the Day-Ahead market model. Minnesota Power queries whether this resulted in other limits being violated downstream on the Minnesota Power transmission system in September 2005. With respect to virtual bids, Minnesota Power maintains that the data on the pattern of cleared bids at the Boise Node indicate that virtual bids do not seem to be a factor in the high LMPs experienced by Minnesota Power on September 13.

[30] A branch flow limit in the Midwest ISO Day-Ahead market model is the maximum flow permitted across a branch in the representation of the transmission grid, such as the Little Fork transmission line or transformer.

27. Minnesota Power also believes that a meaningful review of the data is hindered by the aggregate treatment by Midwest ISO of the Michigan and Minnesota interties with IMO, which are 650 miles apart. Minnesota Power argues that this modeling of the interties results in a market price signal that incents an improper physical response. Minnesota Power states that the current modeling convention being used by Midwest ISO creates a major disparity between the physical flow of power and the actual financial settlements. Minnesota Power continues that the modeling also impedes Minnesota Power's efforts to analyze the information provided by Midwest ISO regarding the high LMPs at the Boise Node on September 13.

28. Minnesota Power concludes by requesting the Commission to direct Midwest ISO to refund, with interest, the alleged excessive charges paid by Minnesota Power. It further asks that, to the extent necessary, the Commission direct Midwest ISO to provide a detailed explanation of the effect on the September 13 LMPs of the phase angle regulator settings, virtual bids, and single interface modeling of the interties with the IMO.

Midwest ISO Answer to Minnesota Power Comments on Confidential Data

29. Midwest ISO argues that there is no basis for Minnesota Power's statement that there may be errors in the September 12 and 13 phase angle regulator flexibility band, stating that Midwest ISO used a reasonable process to establish the phase angle regulator settings and that the results fell within a reasonable range. Midwest ISO further states that adjustment to the phase angle regulator settings on September 14 was to account for additional flows observed in the Day-Ahead case and was not a correction of earlier errors.

30. Midwest ISO states that, contrary to Minnesota Power's contention, it enforces branch flow limits. It says that the 150 MW south and 100 MW north limits cited by Minnesota Power are interface limits for flows between Midwest ISO and the IMO, controlled in Real-Time primarily through non-market mechanisms, such as Transmission Line Loading Relief and the tariff administration process, rather than the branch flow limits on transmission elements, such as transmission lines and transformers, used in the Day-Ahead market model to establish Day-Ahead LMPs.

31. Midwest ISO explains that the Minnesota Power-IMO operating procedure specifies Real-Time operation of the International Falls phase angle regulator and transmission service reservation procedures to protect local equipment (such as the transformer at Little Fork) from thermal overload and to ration its flow. When transmission capacity must be rationed in the Day-Ahead energy market, the value of incremental transmission service is priced directly at the limiting equipment – in this case at Little Falls – rather than on the phase angle regulator at International Falls. Midwest

ISO states that this framework is appropriate for the Day-Ahead market model and no applicable binding constraints are, or were, violated by this approach.

32. Midwest ISO clarifies that the flows at Little Fork were affected by virtual bids in and around Minnesota Power and the IMO region. Midwest ISO notes that the masked data shows that there were 24,685 MWh of virtual transactions submitted throughout the day at the various nodes in these regions and states that the virtual transactions were a factor in the high LMPs on September 13.[31]

33. Further, Midwest ISO notes that the October 23 Order required only that Midwest ISO provide additional "masked" data to Minnesota Power and did not require further explanation of that data. Midwest ISO submits that the Affidavit of Todd Ramey dated May 30, 2006, adequately discussed the role of the phase angle regulator settings and virtual transactions. Midwest ISO also states that Minnesota Power's suggestion that the impact on the Boise Node would have been less severe if the Michigan and Minnesota interties with IMO had been modeled separately is unsupported by any facts. In any case, Midwest ISO notes that the commercial modeling of the IMO intertie as an aggregate is consistent with the way Midwest ISO has been modeling all external balancing authority areas since implementation of Day Two markets. Midwest ISO argues that Minnesota Power has failed to demonstrate any deficiency in such an aggregate model or any material error that requires price correction.

Discussion

Procedural Matters

34. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2006), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

35. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2006), prohibits an answer to an answer, unless otherwise permitted by the decisional authority. We will accept each of the above-noted answers, because these answers have provided information that assisted us in our decision-making process.

[31] Midwest ISO also notes that while virtual bids cleared at the Boise Node only during lower priced hours, there were virtual bids during the higher priced hours that did not clear because they were price responsive.

<u>Analysis</u>

36. The accurate calculation of LMPs is vital to a properly functioning Day Two ISO power market, such as that in Midwest ISO.[32] It is important that power prices reflect market conditions and that LMPs thus reflect legitimate scarcity in the power market. However, price certainty is also important. If power prices are changed after the fact, the resulting uncertainty can undermine the market and investment decisions. Thus, the Commission believes that price corrections must be considered carefully and only in limited circumstances. Reflective of these concerns, the Commission required in the TEMT II Order that Midwest ISO put a price correction procedure into the TEMT that describes the limited circumstances under which a price correction would be implemented by Midwest ISO and the procedure for doing so.[33] The Commission has also held that consistent with the filed rate doctrine, an ISO has the authority, and is required, to correct all prices that do not reflect operation of the ISO's market rules (which are the filed rate).[34]

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[32] *See* discussion of TEMT II Order at *supra* note 2, regarding market operations in Midwest ISO.

[33] *See* TEMT II Order at P 95-96. In the Commission's order accepting the price correction procedure in section 48 of the TEMT, the Commission emphasized that "[f]lawed prices due to market implementation errors or emergency system conditions need to be corrected quickly, to sustain confidence in the market. At the same time, there needs to be quick notification to the market of any impending price changes, to preserve price certainty." *See* TEMT II Compliance Order at P 67.

[34] *See ISO New England, Inc.*, 90 FERC ¶ 61,141, at 61,425 (2000) (*ISO New England*). We note that due to the timing of Minnesota Power's raising of the Boise Node pricing issue to Midwest ISO, the requested price correction fell outside the timeframe for any price correction under section 48 of the TEMT. However, as discussed in *ISO New England*, should Midwest ISO not have followed the TEMT in calculating the LMPs, changes to the LMPs might have been ordered in any case, in order for Midwest ISO to comply with the filed rate doctrine. *See also NRG*. As discussed more fully below, we do not find that Midwest ISO violated its market rules in the TEMT in its calculation of the LMPs on September 13, and accordingly, Midwest ISO has not violated the filed rate doctrine.

Market Implementation Error versus Market Conditions

37. In order to determine that there should be a price correction at the Boise Node, it must first be shown that a market implementation error occurred or the TEMT was implemented incorrectly, such that the LMPs at the Boise Node do not reflect the operation of market rules as provided in the TEMT. All parties agree that Midwest ISO updated its assumptions about the phase angle regulator and loop flows after the high LMPs at the Boise Node on September 13. However, the fact that Midwest ISO did so does not mean that the previous assumptions constituted a market implementation error, nor does it imply that Midwest ISO has admitted to such a market implementation error.[35] The focus of the inquiry then is to examine why LMPs rose at the Boise Node and whether the model functioned properly to produce those LMPs, in order to determine if a market implementation error was involved and if the TEMT was implemented correctly or not. We first compare the circumstances on September 12 and 13, and then those on September 13 and 14.[36] As discussed below, our review of the data reveals a reasonable explanation for the significant differences in the LMPs experienced on September 12, 13, and 14.

September 12 and 13

38. Both September 12 and 13 were characterized by significant loop flows and exports to the IMO.[37] South to north flows over the Little Fork transformer are sensitive

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[35] *See New York Independent System Operator*, 110 FERC ¶ 61,244, at n. 67 (2005) ("Just as evidence of future repairs is not deemed evidence of negligence (Fed. R. Evid. 407), NYISO's proposed change in market design does not establish that its past market design was so flawed as to justify the imposition of [price correction procedures].") We note that Midwest ISO's statement in its October 24, 2005 e-mail to Minnesota Power that "[Day-Ahead] Market cases have been reviewed and updated to more accurately reflect conditions expected to occur in [Real-Time]" also does not constitute an admission of error by Midwest ISO, but rather points to improvement of the model.

[36] Our discussion below is based on the public data provided by the parties, however, our review of the confidential information provided by Midwest ISO on August 10, 2006 in response to Commission Staff's July 11, 2006 data request supports our findings herein.

[37] Loop flow on September 12 at the IMO interface was virtually identical to loop flow on September 13, as reported in the Midwest ISO response to the data request filed on August 10, 2006.

to these flows to the IMO. The flows to the IMO pulled power from Minnesota through the connections to the IMO at the Minnesota-Canada border where the Little Fork transformer and the Boise Node are located. Because the loop flows and exports were high on both days, they resulted in significant flows on the Little Fork transformer on both September 12 and September 13.

39. There were, however, also important differences in the market conditions between the two days; market conditions on September 13 (but not on September 12) resulted in a constraint at Little Fork and high LMPs at the Boise Node. First, on September 13 (as compared to September 12), demand shifted from the west to the east. In particular, demand fell relative to supply in the western portion of the Midwest ISO (Minnesota and the states in the Mid-Continent Area Power Pool (MAPP) region). Meanwhile, demand increased relative to supply in Midwest ISO states east of Minnesota. These changes resulted in increased power flows from Minnesota and the MAPP region to eastern portions of Midwest ISO and resulted in transmission constraints. These constraints developed in Minnesota on flows both from west to east, into Wisconsin and other areas, and also on flows from south to north through the Little Fork transformer, as increased flows to the east pulled power north from Minnesota through Little Fork to the IMO and through the Canadian portion of the transmission system, as it traveled east. The effect of the constraints on September 13 was lower LMPs in portions of Minnesota Power south of Little Fork compared to higher LMPs at the Boise Node and in the IMO.

40. Second, the constraints at Little Fork were expensive to resolve, making those LMP differences significant. As Todd Ramey of the Midwest ISO discusses, if load at the Boise Node is inflexible then reducing IMO transactions is the most cost-effective means of managing the constraint at Little Fork.[38] Demand at the Boise Node was inflexible, so the model turned to other flows over the Little Fork transformer, such as export transactions to the IMO, as well as to virtual bids at any location that could cause increased flows at Little Fork. However, when the Day-Ahead market model can no longer reduce exports to the IMO to reduce flow at Little Fork (either because there are inflexible export transactions that must be taken regardless of price or because there are high-priced bids at the IMO), it becomes necessary to reduce generation in areas that are contributing to south to north flows at Little Fork. This means that on September 13, the Day-Ahead market model had to back down Minnesota Power generation south of Little Fork and in neighboring Otter Tail Power and Northern States Power. Because a large reduction in generation in these areas is needed to reduce flows on the Little Fork transformer, the cost of reducing flows on the Little Fork transformer was very high. Since the LMP at the Boise Node is, in turn, very sensitive to the cost of controlling congestion at Little Fork, the LMP at the Boise Node was also very high.

[38] Ramey Affidavit at 6-7.

41. These same factors caused LMPs to the south and west of the Boise Node to be lower on September 13 than they were on September 12 and generally lower than other areas in Midwest ISO. This resulted in a large price difference between the Boise Node and these areas.

42. Another difference between September 12 and September 13 is that the base transformer rating at Little Fork on September 13 was higher than on September 12, allowing more megawatts to move north through Little Fork. This adjustment would, however, tend to keep LMPs lower at the Boise Node than they otherwise would have been.

43. In sum, the pattern of LMPs on September 12 and 13 is consistent with the conclusion that the Day-Ahead market model's rationing of scarce capacity at Little Fork was the cause for the high LMPs at the Boise Node. The data on September 12 and September 13 does not suggest that the Boise Node LMPs on September 13 were the result of a model flaw or market implementation error, nor does it suggest that the Boise Node LMPs do not reflect proper operation of Midwest ISO's market rules in the TEMT. Rather, this data suggests that the difference in LMPs between September 12 and 13 resulted from the underlying demand and supply in the market.

September 13 and 14

44. Demand across the Midwest ISO system dropped and exports to the IMO fell on September 14, as compared to September 13. Overall, Midwest ISO demand on September 14 was between 8,000 and 10,000 MW lower than on September 13. As such, the combination of demand and supply factors relieved the constraint and brought LMPs down at the Boise Node on September 14, as compared to September 13.

45. With respect to Midwest ISO's revising the phase angle regulator and branch flow settings within the model on September 14, the effect of these changes on the LMPs at the Boise Node is not clear. This is because the adjustments Midwest ISO made move in opposite directions: one adjustment would have the effect of reducing flows (which would have worked toward relieving a constraint at Little Fork), while the other adjustment reduced capacity (which would have furthered any constraint). This is because Midwest ISO not only increased the range of operation of the phase angle regulator, but also decreased the branch limit on the Little Fork transformer. The phase angle regulator adjustment made would increase the ability to adjust flows on the local transmission facilities and hence reduce flows over the Little Fork transformer, while the lowering of the branch limit would decrease the capacity of the Little Fork transformer.[39]

[39] The rating on the Little Fork transformer was raised from the normal rating on September 12 to the emergency rating on September 13.

It is reasonable to regard this adjustment as an improved representation of the operation of the phase angle regulator in the Day-Ahead market model. However, the previous approach (used on September 13) of increasing the branch limit above the normal limit under high flow conditions was another reasonable configuration for the Day-Ahead market model to use to anticipate potential Real-Time conditions. The occurrence of these kinds of adjustments is not evidence of a market implementation error or misapplication of the market rules in the TEMT.[40]

Lack of a Market Implementation or Other Market Rule Error

46. We find that the record does not support a showing that a market implementation error was the cause of the high prices experienced at the Boise Node on September 13. We agree with Midwest ISO that, in fact, no market implementation error occurred on September 13. While it is not possible to isolate a single cause of the high LMPs at the Boise Node on September 13, we agree with Midwest ISO that the high LMPs at the Boise Node on September 13 resulted from a combination of bids and offers in the Day-Ahead market model; the shifting of Day-Ahead injections and withdrawals; demand bids at the Boise Node; virtual bids that increased flows at Little Fork; inflexible exports to the IMO; as well as loop flow assumptions and phase angle regulator settings. These input factors to the Day-Ahead market model combined to create constraints at the Little Fork transformer on September 13 that were very expensive to resolve and that also created high congestion prices at the Boise Node (resulting from the sensitivity of the Boise Node to the constraint at the Little Fork transformer). None of these factors indicate a flaw in the design or implementation of the Day-Ahead market software or misapplication of the market rules in the TEMT, and therefore, we find that no market implementation error occurred on September 13 and there was no violation of the filed rate doctrine on September 13.

47. We conclude that the Day-Ahead LMPs at the Boise Node on September 13 increased due to legitimate market conditions and reflected supply and demand in the market and the associated relative scarcity at the Boise Node. Subsequently, Day-Ahead LMPs on September 14 at the Boise Node fell due to reduced overall demand and reduced exports to the IMO as discussed above. Similarly, we find no evidence that market implementation errors or incorrect LMPs caused the FTR losses alleged by Minnesota Power. There is no evidence that Midwest ISO made errors in its modeling assumptions or in the implementation of its market rules in the TEMT.[41]

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[40] *See supra* discussion at P 37 and note 35.

[41] More generally, we note that atypically high prices on a given day or in a specific region do not alone show a market implementation error that would lead to a price correction under the TEMT. Given specific conditions in the market such as

(continued….)

48. Indeed, it appears that Midwest ISO's system adjustments (raising the base ratings at the Little Fork transformer and transmission line) likely helped keep LMPs on September 13 lower at the Boise Node than they would otherwise have been. We also note that only a small portion of Minnesota Power's total load occurs at the Boise Node. Consequently, Minnesota Power's calculation of the costs of the high LMPs on September 13 – based only upon the LMPs at the Boise Node while ignoring the LMPs at other Minnesota Power nodes that were driven down – makes for a poor measure of any overall cost effects upon Minnesota Power. Such an approach ignores the fact that the same congestion at Little Fork that caused a price increase on a small number of MWs at the Boise Node also caused a significant price decrease on a large number of MWs in the remainder of the Minnesota Power service area.

Other Arguments

49. We find Minnesota Power's assertion that the aggregate treatment of the Michigan and Minnesota interties as a single external interface contributed to the higher prices at the Boise Node to be unsupported. The use of a single external interface is a market design choice that is consistent with the treatment of interfaces between other RTOs, such as PJM and New York ISO, and Minnesota Power has not shown any reason to consider the use of a single external interface to be a market implementation error. Moreover, given that the market has been modeled in this manner since its inception, it is also unclear how this caused an improper physical response just on September 13.

Conclusion

50. We find that there was no market implementation error associated with the high LMPs at the Boise Node or FTR losses by Minnesota Power on September 13. The market rules in the TEMT were properly applied and there is no need for a price correction under the filed rate doctrine. Accordingly, we deny Minnesota Power's complaint.

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outages and inflexible demand, prices can climb high any one day in any specific location. Such price increases reflect conditions in the market on that day and at that location, and section 48.1 of the TEMT expressly provides that market implementation errors and emergency system conditions do not include situations in which prices rise to levels based on demand and supply levels determined by efficient competition in periods of relative scarcity, or fall to levels based on demand and supply levels determined by efficient competition in times of relative surplus.

<u>The Commission orders</u>:

Minnesota Power’s complaint is hereby denied, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.